USING ROD GUIDES EFFECTIVELY IN VERTICAL WELLS: WEST TEXAS WATERFLOOD CASE HISTORY

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ABSTRACT

Metal to metal contact shortens the run life of both tubing, steel and fiberglass sucker rods. Using sacrificial rod guides can extend this life at the expense of increased side and axial loading enhanced by Coulomb friction effects. The problem is not limited to directional and horizontal wells. Just how crooked are our vertical wells? Simple inclination surveys insufficiently describe the wellbore path drilled. Knowledge of failure history, inclination and azimuth of wellbore path, plus access to a rod design program provide insight into effective placement of rod guides and longer run life. A case history from an established West Texas waterflood is presented to illustrate the application.

INTRODUCTION

Production fields in the Permian Basin frequently represent a series of multiples: well count and age, operators and operating philosophies, formations and completion techniques, and artificial lift to name the most common. The fifteen wells cited in this paper are similar in many respects. Seven different operators drilled them between 1935 and 1999. Prior histories show five of these wells deepened and one well plugged back from the original producing horizons. All are currently sucker rod pumped and part of an ongoing waterflood started in 1968 by a previous operator. In this paper, the actual well number only identifies wells.

CHALLENGE

Extending run life is the challenge every production operator faces. Longer run life pushes the economic life further into the future because operating expenses to repair failures are lower. Focus on failure reduction is particularly keen during periods of low commodity prices. Interrelated variables including down hole pressure, temperature and chemistry, wellbore geometry, equipment cost, availability, age (or fatigue cycles experienced), manufactured quality as well as care and handling all may combine to complicate sucker rod failure reduction efforts. Drilling sets the wellbore geometry for the life of a well. Measuring and evaluating that geometry in the fifteen wells mentioned is the subject of this paper with the objective of extending the mean time between sucker rod failures.

WELLBORE GEOMETRY AND CONTACT

Metal to metal contact, whether from drill pipe tool joints rotating inside casing or steel rods reciprocating inside tubing, is a wear agent for premature failure of one or both surfaces. Drag forces increase from rubbing contact between rods and tubing, which in turn, raises side and axial rod loadings (Figure 1). In deviated wellbores, the Coulomb friction effects are added to the Wave Equation (for sucker rod motion) to describe these drag forces (Figure 2).

Additionally, repeated contact initially wipes off protective chemical inhibitor film, mill scale if present, that eventually exposes bare metal to corrosive fluids accelerating subsequent failure. Parting of equipment, rod wear and certain corrosion failures may be symptomatic of contact failure (Figure 3).

This past year following a down hole failure and an apparent history of contact-related failures, gyroscopic surveys to assess wellbore geometry were run in fourteen of the fifteen wells (one had a survey recorded during its plug back recompletion). The intent being to mitigate contact failures by installing molded rod guides placed as efficiently as possible. Grouping each well's mean time between failures by decade of recorded history, most wells show a decreasing number of days between failures over time. Although run time improvements in the latest decade are evident on five of the wells, only one well ran more than two years on average between failures (Figure 4).

WELLBORE GEOMETRY EVALUATION

The fifteen wells are scattered across a Permian age anticlinal carbonate structure in West Texas (Figure 5). Gyroscopic surveys of inclination and azimuth using the minimum curvature method were obtained for the latest fourteen surveys. The calculation method is unavailable for the earlier survey. Survey stations are every 100 feet of measured depth through anchored production tubing. Creating combined plots of displacement from vertical versus measured depth and plan view for all fifteen wells reveals no definitive pattern. However, all wells surveyed deviate from vertical more than the length of a steel sucker rod (25 feet commonly) and more importantly, directionally measuring the wellbore path should increase the probability of successful placement of sacrificial wear surfaces (rod guides) than using other indicators, such as inclination surveys and/or failure history, alone.

All rod designs were evaluated with GE-Lufkin's SROD program sequentially – before "gyro", after "gyro", and "gyro" with added rod guides, in several instances making stroke length and/or pumping speed changes to optimize performance. Because rod guides deliberately increase drag forces by centralizing the rod through contact points, it is both load reducing (side and axial) and cost effective (less rods to purchase) to use as few guided rods as possible.

Use of rod guides is not new in this waterflood; records indicate the first applications date to the early 1990s. Having a directional survey to guide their placement is new. The cost to obtain a survey is equivalent to the cost of one day of pulling unit time. One less failure in the first year following survey will justify this expense.

Standard practice is to install rod guides only where dogleg severity exceeds three or more degrees per 100 feet. Only two of the fifteen wells meet the criteria: 105 and 1403. Yet, all exhibit contact failures historically. Of the first eight wells surveyed, seven had rod guides installed based upon the dogleg severity and depth of prior contact failures. The eighth well (1203) did not. It failed down hole a few days before publishing time so, the cause is yet unknown. The first group of eight wells indicated by solid lines in Figures 4 and 5; their comparative run times depicted in Figure 4.

MAXIMUM RELATIVE DOGLEG SEVERITY

Dogleg severity helps quantify potential problem intervals using directional information. As defined though, it analyzes survey data on a point-to-point basis. Three- dimensional views of wellbore path suggest that the effect of changes in direction may involve more than adjacent points (Figure 6). Calculating dogleg severity, without honoring strictly adjacent measurements, for all combinations of survey points may help quantify the relative effect of nonadjacent measurements (Figure 7).

This technique is described using 701 as an example. Dogleg severity is minimal, much less than three degrees per 100 feet at any point in the wellbore. But, the "3-D Wellbore Path", plan view, displacement from vertical and plethora of failures over multiple depths say otherwise (Figure 8). A matrix of relative dogleg severity, abbreviated to a 10x10 grid for illustration purposes, is generated by calculating the dogleg severity of each depth point with that of every other depth point (Figure 9). Plotting relative dogleg severity versus measured depth, the absolute maximum dogleg severity is selected for each survey depth. Note: relative dogleg severity is a positive value for depths above each survey depth and negative for each depth below, simply the nature of the formula. These maximum values are then plotted next to the standard values. The maximum values may extend the length of the interval of concern posed by the standard dogleg severity. This extension is frequently up hole from the standard value; ironic, because at the latest local artificial lift forum, a verbal complaint about rod guides is that the next failure is usually right above the uppermost guide. Finally, the design program (SROD) is rerun with the proposed guide placement based on the maximum relative dogleg severity in combination with prior contact failure depths to check loadings (Figure 10). Unfortunately, SROD is currently limited to ten-rod segments for design. Adequate safety margin must be factored in if more than ten segments are planned.

The 3-D wellbore path, dogleg severities, and failure depths of the six wells (excluding 701) also with rod guides placed using the new technique are displayed for reference (Figures 11 and 12). Seven wells using this new technique including 701 are drawn with dashed lines in Figures 4 and 5.

OBSERVATIONS

At publishing time, six of the seven wells (1203 excluded – failed without rod guides) with a gyro survey and molded rod guides using conventional placement have already exceeded their average run time this decade. Of the seven wells utilizing the new technique, the first well retrofitted (105) already exceeded its average run time this decade. One well utilizing the new technique, 9354, failed down hole a few days before publishing time; like 1203 – cause unknown. Unlike 1203, which does not have rod guides, 9354 does have them. Well 9354 is unique though in two aspects. It is the only one of the fifteen wells using fiberglass rods and sinker bars. Approximately half of its failures in the past five years are across the sinker bar interval; poly-lined tubing was added during the latest repair to eliminate metal-to-metal contact. Running two extra joints of tubing to cover the upper sinker bar-tubing overlap may be insufficient. Second, rod guides were added to the lower portion of the fiberglass rods. Fiberglass rods with molded rod guides are stocked irregularly in West Texas. The well was back online approximately one month before retrofitting. Either of these issues may have resulted in failure if not something else entirely.

As mentioned, recent gyro surveys used the minimum curvature method, which is generally now standard. It is considered the most accurate of the available methods. However, recalculating the vendor-provided dogleg severity should be routine, particularly if validating older data, which may have used another method (Figure 13).

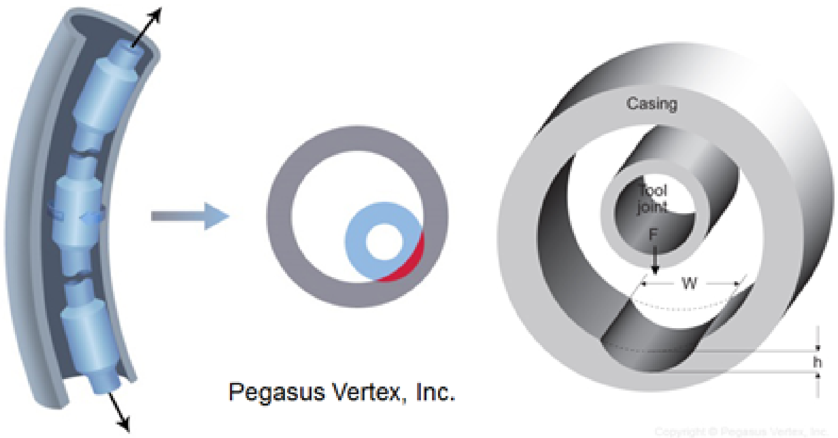
Even with reasonable side and axial loading, eventually the guide material will wear thin. Monitoring loading to replace proactively a worn guided rod before it cuts into the tubing will also reduce failure expense.

CONCLUSIONS

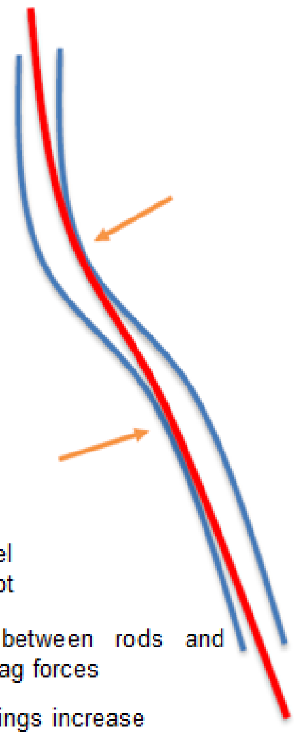
Knowledge of wellbore path gained through directional surveys can lead to effective use of rod guides in combating failures caused by metal-to-metal contact. Fewer failures mean longer run time and improved production recovery efficiency. Stretching the definition of dogleg severity from a point-to-point basis to that of a matrix creates to a relationship between directional survey stops, expanding the extent of apparent wellbore crookedness, which may aid in the effective placement of rod guides.

REFERENCES

1. Bang, J., Jegbefume, O., and Thompson, J. 2015. Wellbore Tortuosity Analysed by a Novel Method May Help to Improve Drilling, Completion, and Production Operations. *SPE/IADC 173103*.
2. Gibbs, S. G. 2012. *Rod Pumping: Modern Methods of Design, Diagnosis, and Surveillance*.
3. Discussion following presentations at 21th Annual – 2015 Permian Basin Artificial Lift Forum, Midland, TX.
4. API D20, Bulletin on Directional Drilling Survey Calculation Methods and Terminology. 1985. API: Washington, D.C.



Pegasus Vertex, Inc.



Metal to metal contact : whether from drill pipe tool joints on casing or from steel rod couplings on tubing, equal opportunity wear agent for premature failure. Not to mention lovely crescent-shaped grooves.

Rubbing contact between rods and tubing increases drag forces

Side and axial loadings increase

SPE/IADC 173103 • Wellbore tortuosity • Jon Bang

Figure 1

Wave Equation:

$$\frac{\partial^2 y(s,t)}{\partial t^2} = \upsilon^2 \frac{\partial^2 y(s,t)}{\partial s^2} - c\,\frac{\partial y(s,t)}{\partial t} - \overbrace{C(s) + g(s)}^{\textbf{Coulomb factor}}$$

$$C(s) = \delta \mu(s) \left[Q\,(s) + T\,(s) \frac{\partial\, y(s,t)}{\partial s} \right]$$

$$\delta = \frac{\partial y(s,t) / \partial t}{|\partial y(s,t) / \partial t|}$$

Gibbs, ROD PUMPING: Modern Methods of Design, Diagnosis and Surveillance, 2012

Figure 2

Photos courtesy of WadeCo Specialties

Figure 3

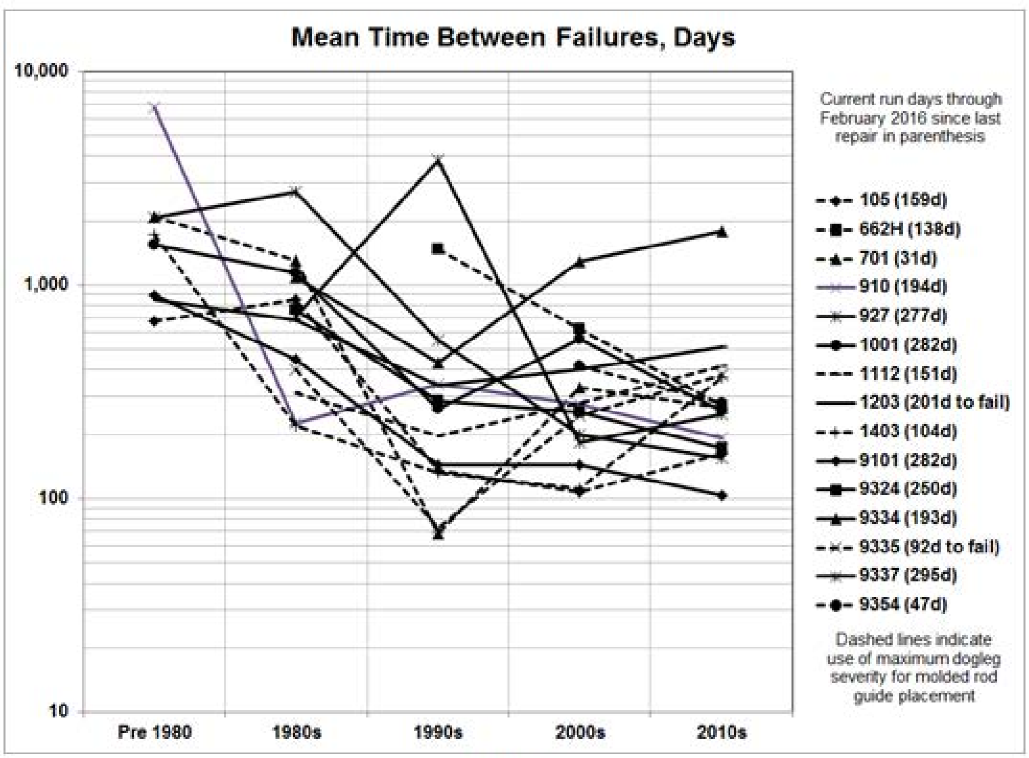
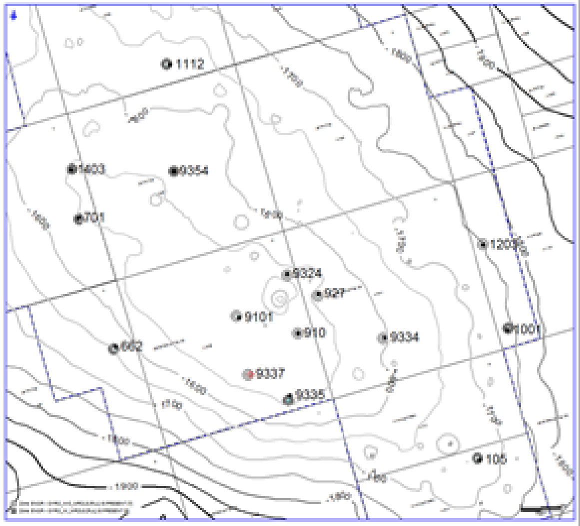
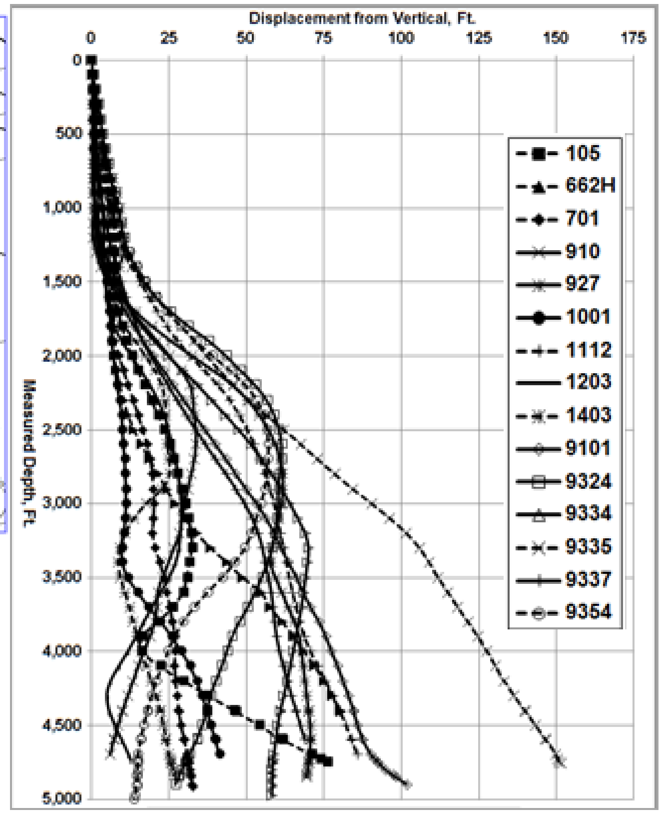


Figure 4

Well Locations





Note: All wells with gyroscopic surveys used to position molded rod guides shown; wells with dashed lines represent use of maximum relative dogleg severity in positioning molded rod guides.

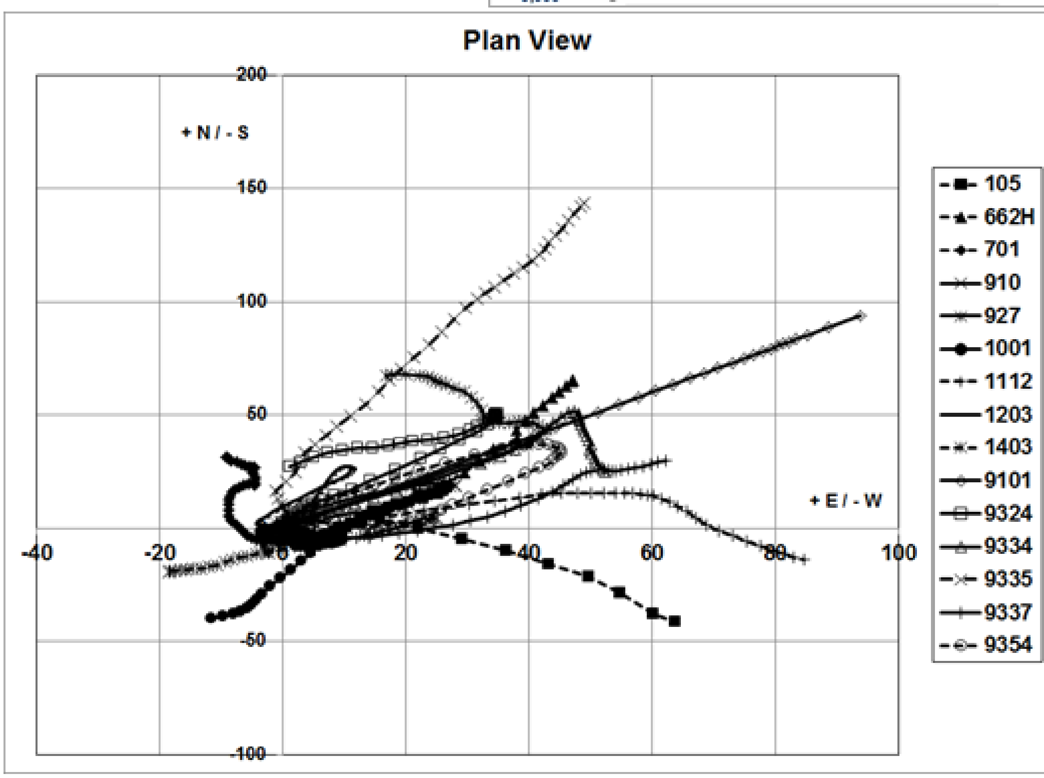


Figure 5

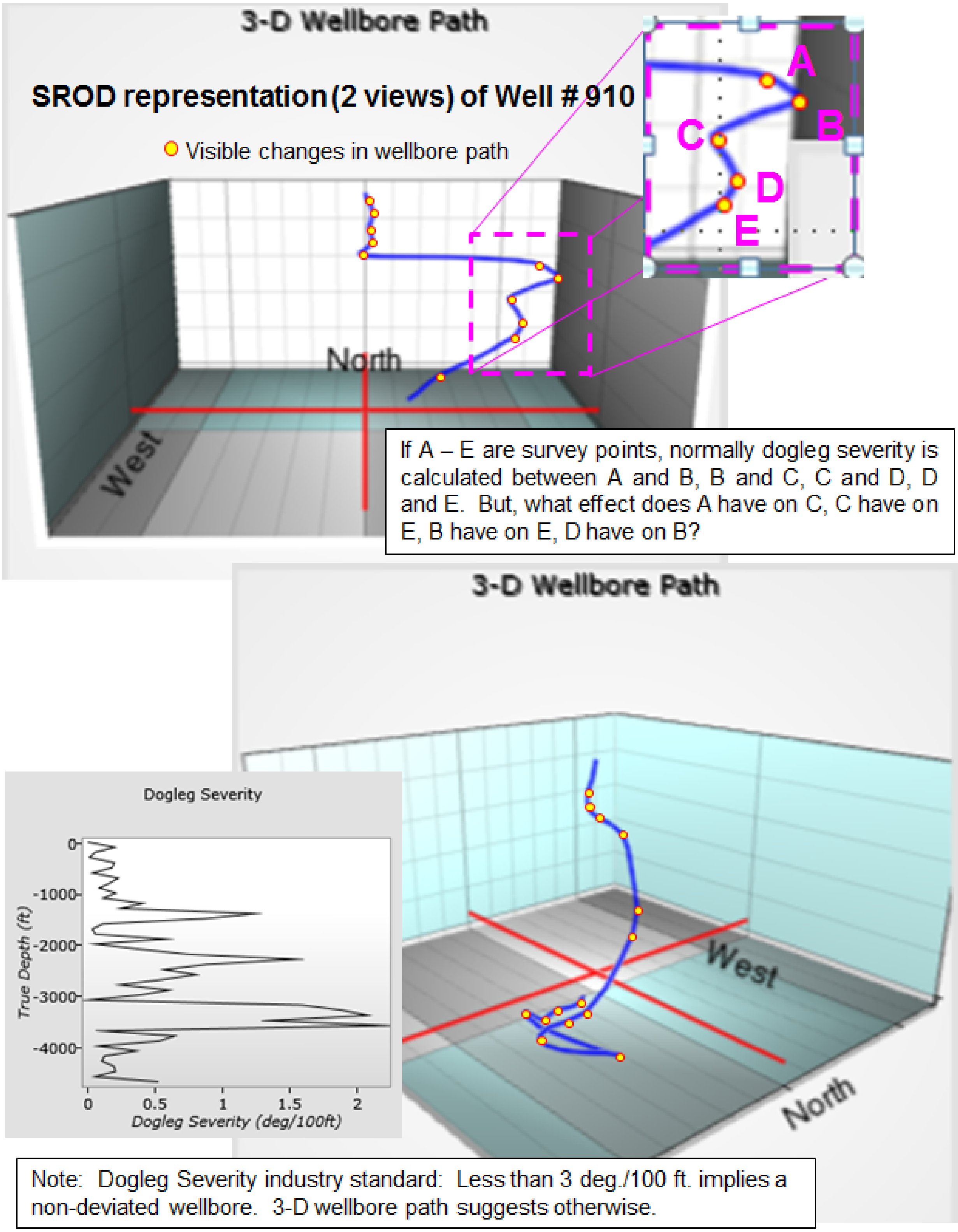

3-D Wellbore Path
SROD representation (2 views) of Well # 910
Visible changes in wellbore path
A
B
C
D
E
North
West
If A – E are survey points, normally dogleg severity is calculated between A and B, B and C, C and D, D and E. But, what effect does A have on C, C have on E, B have on E, D have on B?
3-D Wellbore Path
West
North
Dogleg Severity
True Depth (ft)
0
-1000
-2000
-3000
-4000
0
0.5
1
1.5
2
Dogleg Severity (deg/100ft)
Note: Dogleg Severity industry standard: Less than 3 deg./100 ft. implies a non-deviated wellbore. 3-D wellbore path suggests otherwise.

Figure 6

Dogleg Severity

- Measures the change in inclination and/or azimuth in degrees per 100 feet (30 meters)

- $$DLS = 100\,\frac{\left(\arccos[\cos\alpha_1 \cos\alpha_2 + \sin\alpha_1 \sin\alpha_2 \cos\Delta Az]\right)}{MD_2 - MD_1}$$

  where, dogleg severity is in degrees/100’

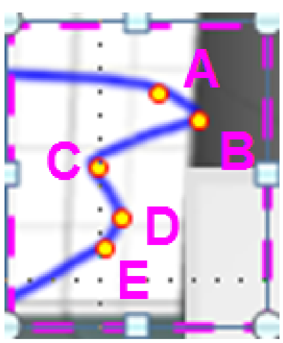
  α is the inclination in degrees,

  Az is the change in azimuth in degrees,

  MD is the change in measured depth in feet,

  1, 2 are adjacent measurements

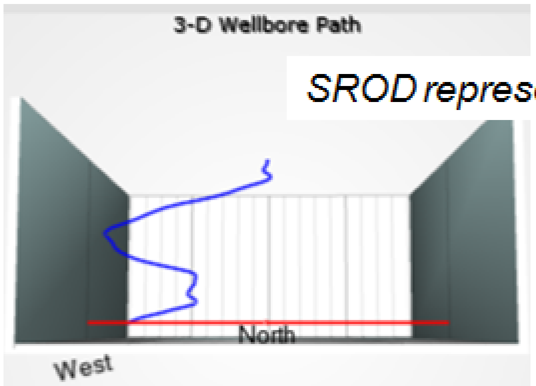
- Using the same formula without honoring adjacent measurements only may help quantify the relative effect of nonadjacent measurements



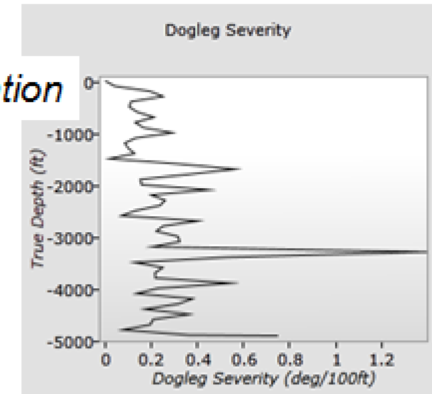
All combinations of survey measurements

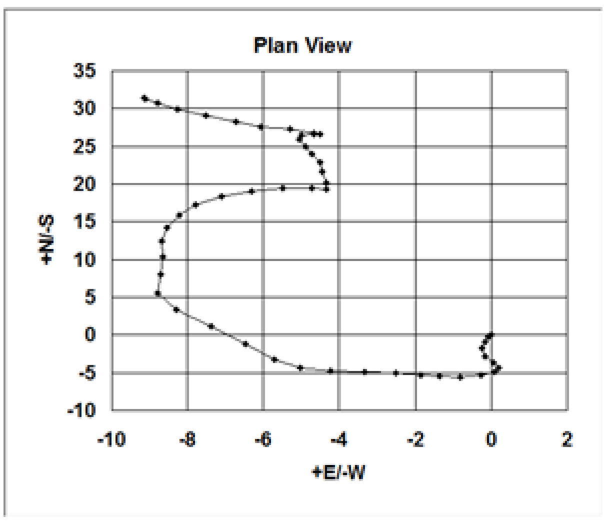
Figure 7

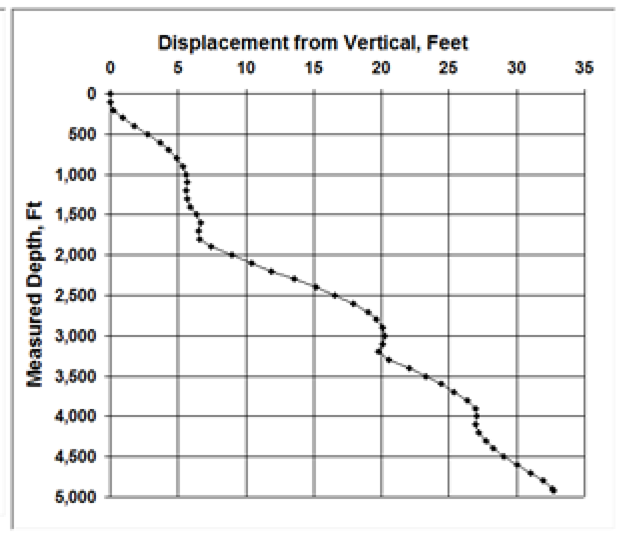
Well # 701 – gyro survey results

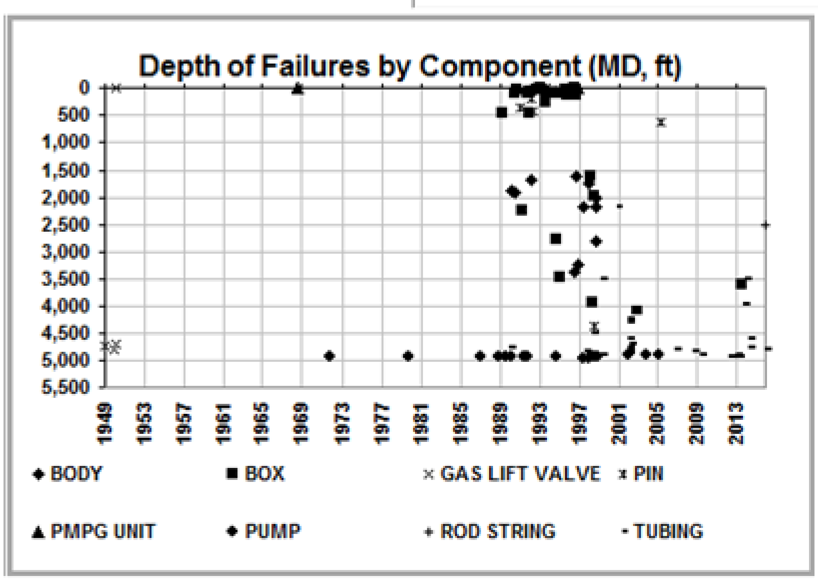


SROD representation







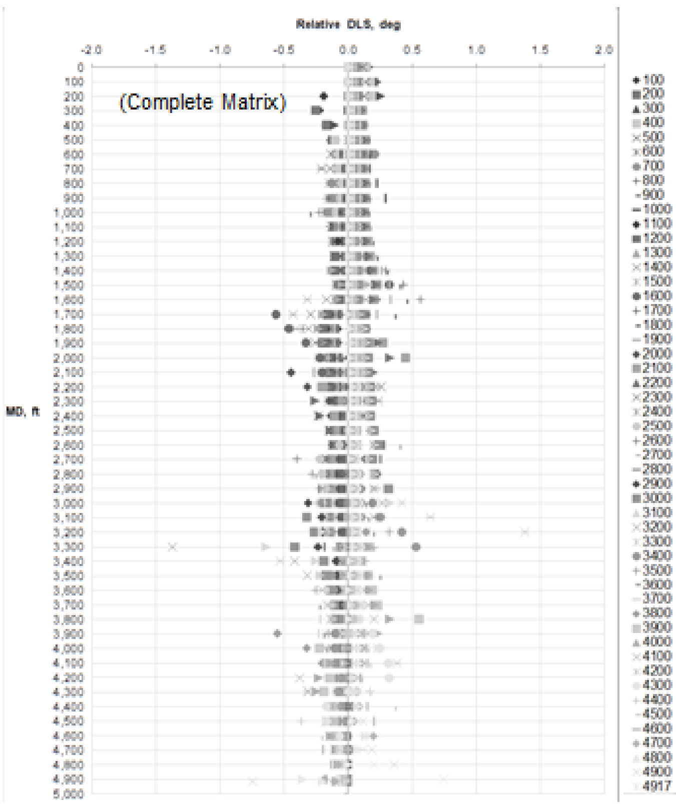


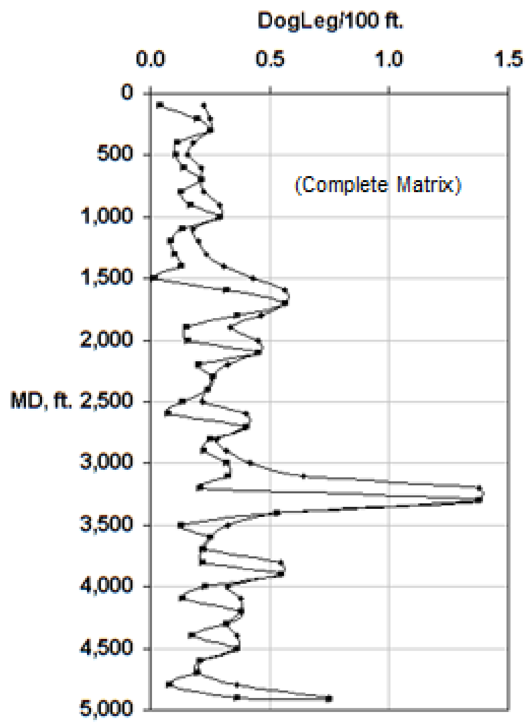
Taking failure history into account equally important

Figure 8

Well # 701

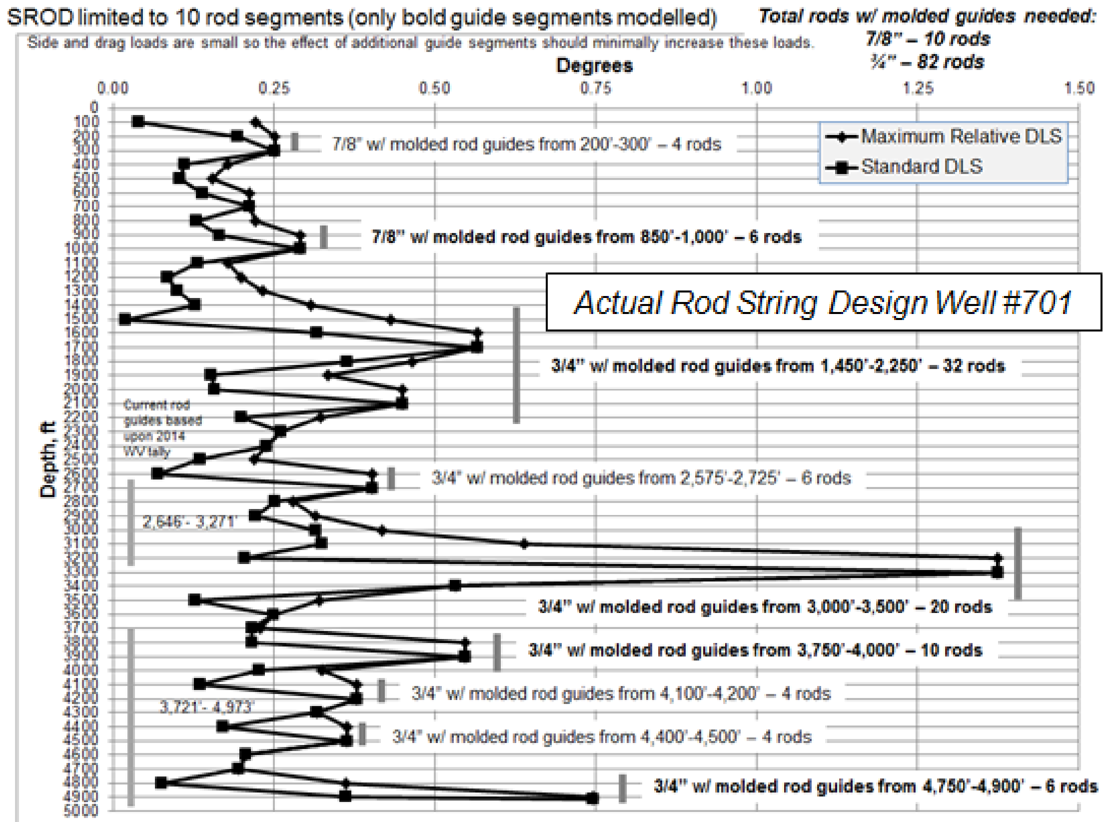
				Maximum Relative Dog Leg Severity (partial matrix shown below)									
Actual Survey Pts. - # 701				0.2222	0.2506	0.2506	0.1790	0.1534	0.2120	0.2120	0.2221	0.2915	0.2915
Measured	Inclination	Azimuth	Depth, Feet	100	200	300	400	500	600	700	800	900	1000
Depth (ft.)		Bearing	0	0.0400	0.1150	0.1600	0.1425	0.1160	0.0783	0.0429	0.0450	0.0389	0.0380
100.00	0.04	213.94	100.00	0.0000	0.1938	0.2222	0.1790	0.1379	0.0894	0.0446	0.0459	0.0389	0.0402
200.00	0.23	190.91	200.00	-0.1938	0.0000	0.2506	0.1731	0.1245	0.0734	0.0169	0.0232	0.0307	0.0527
300.00	0.48	187.88	300.00	-0.2222	-0.2506	0.0000	0.1116	0.0948	0.0735	0.0466	0.0304	0.0512	0.0849
400.00	0.57	180.64	400.00	-0.1790	-0.1731	-0.1116	0.0000	0.1040	0.1011	0.0900	0.0657	0.0837	0.1176
500.00	0.58	170.31	500.00	-0.1379	-0.1245	-0.0948	-0.1040	0.0000	0.1384	0.1448	0.1085	0.1223	0.1534
600.00	0.47	161.08	600.00	-0.0894	-0.0734	-0.0735	-0.1011	-0.1384	0.0000	0.2120	0.1500	0.1536	0.1780
700.00	0.30	180.51	700.00	-0.0446	-0.0169	-0.0466	-0.0900	-0.1448	-0.2120	0.0000	0.1301	0.1318	0.1667
800.00	0.36	200.74	800.00	-0.0459	-0.0232	-0.0304	-0.0657	-0.1085	-0.1500	-0.1301	0.0000	0.1652	0.2221
900.00	0.35	227.60	900.00	-0.0389	-0.0307	-0.0512	-0.0837	-0.1223	-0.1536	-0.1318	-0.1652	0.0000	0.2915
1000.00	0.38	274.45	1000.00	-0.0402	-0.0527	-0.0849	-0.1176	-0.1534	-0.1780	-0.1667	-0.2221	-0.2915	0.0000
				Relative Dog Leg Severity Matrix (partial matrix shown above)									

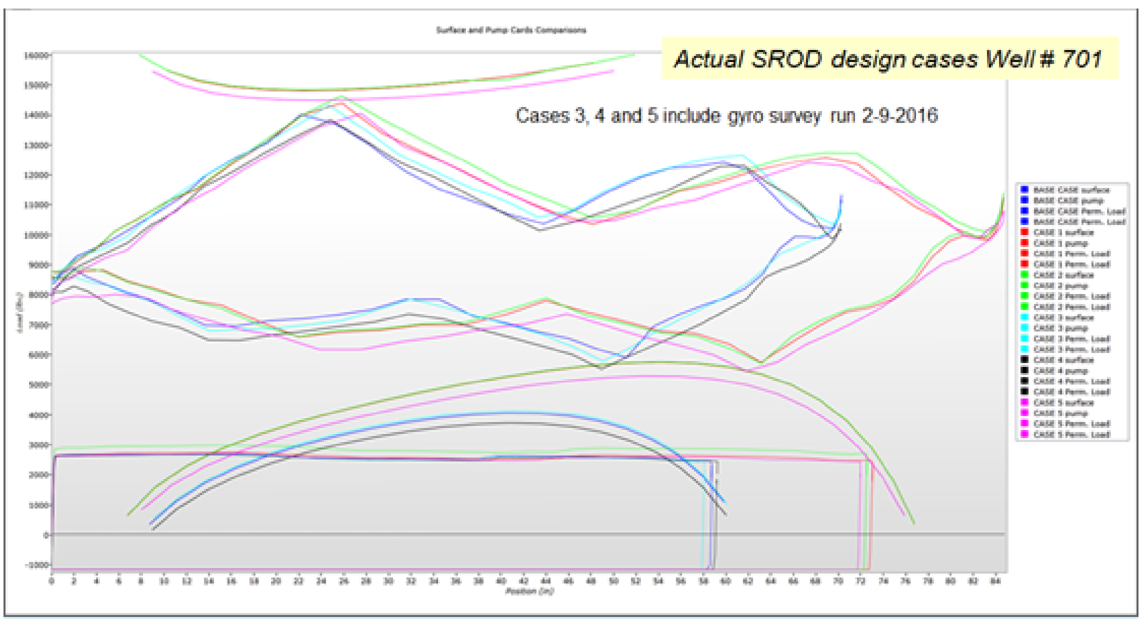




Maximum relative dogleg severity is the maximum absolute value of calculated dogleg severity of every survey depth versus a particular survey depth.

Figure 9





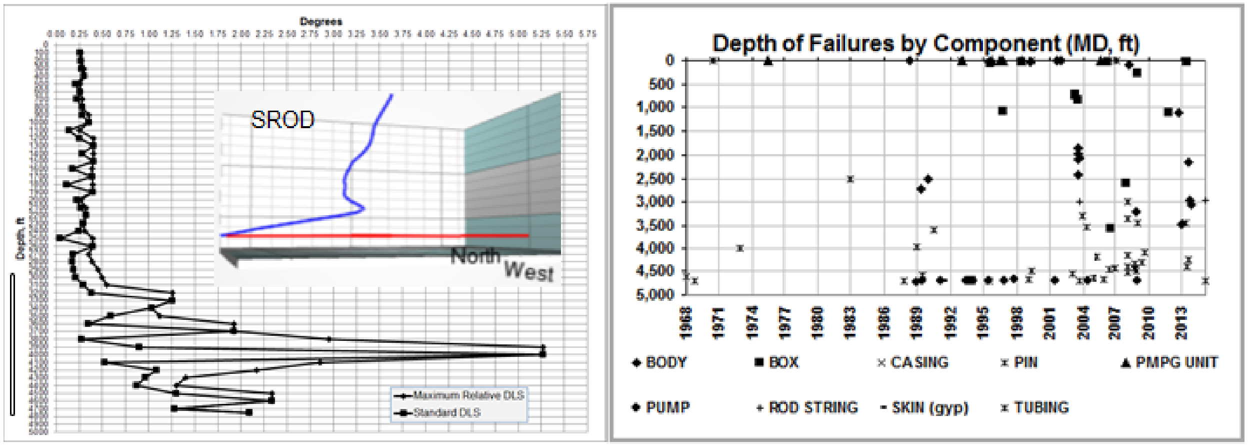
MRG = molded rod guides
Case 3 has "other" guides
(probably snap-on)

	PPRL/ MPRL	% Motor Load	% GB Load	SL	SPM	% Rod Load (S.F. = 1) 7/8"	7/8" w/ MRG	3/4"	3/4" w/ MRG	3/4"	3/4" w/ MRG	3/4"	3/4" w/ MRG	3/4"	3/4" w/ MRG	BPD	% Pump Eff
Case 3 – Base Case w/ gyro	0.403	40.4	75.5	70.3	8.51	57		58	49	42	39					25.90	20.08
Case 4 – Redesign rod string	0.399	40.0	72.6	70.3	8.51	55	47	66	61	53	46	41	39	36	30	105.6	80.00
Case 5 – Case 4 plus SL/SPM	0.388	48.2	90.9	84.8	8.00	56	48	67	62	54	46	41	39	37	30	120.8	80.00

Figure 10

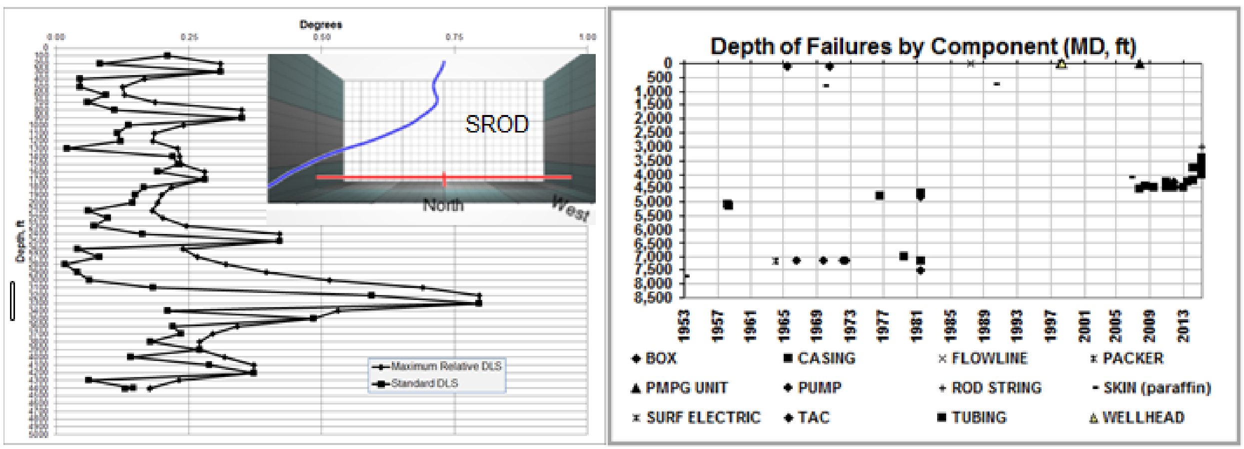
Note: MRG abbreviation for molded rod guides

105



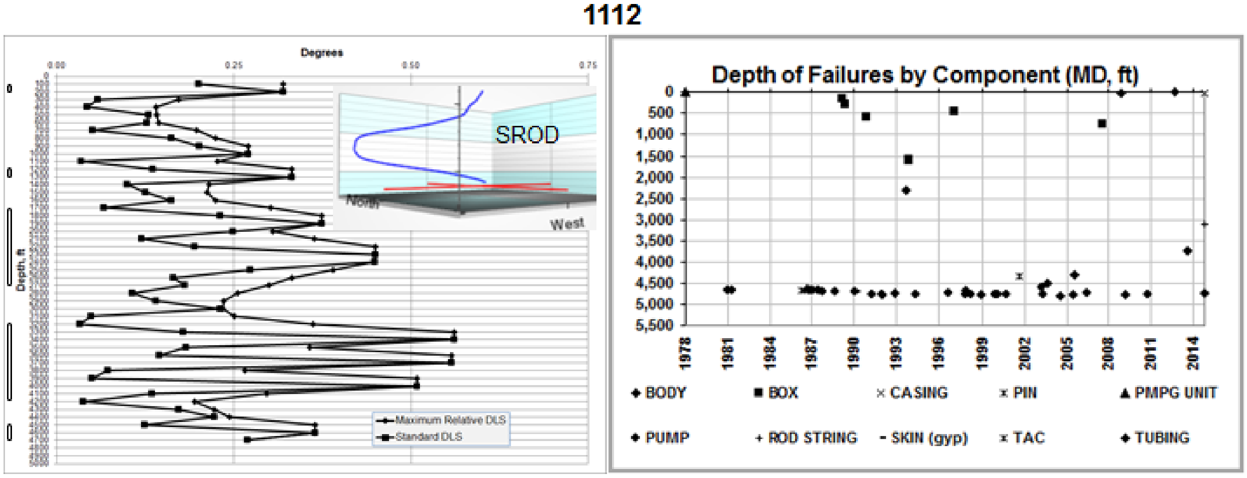
3/4" Steel Rods w/ MRG

662H



3/4" Steel Rods w/ MRG

1112



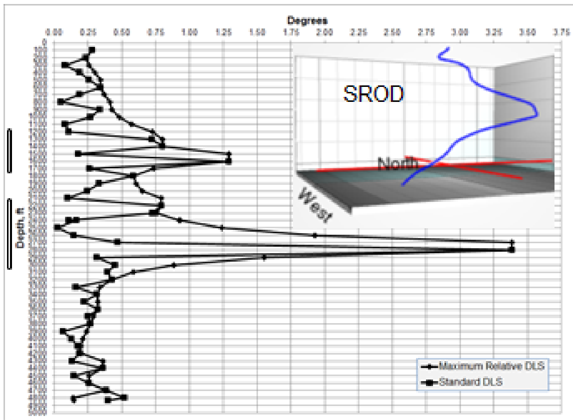
7/8" Steel Rods w/ MRG

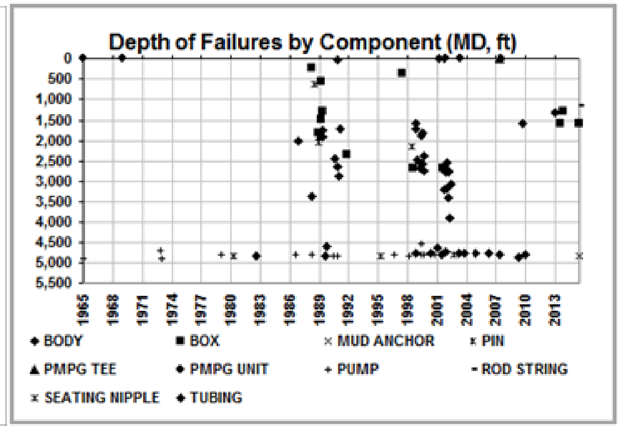
3/4" Steel Rods w/ MRG

Figure 11

1403

Note: MRG abbreviation for molded rod guides

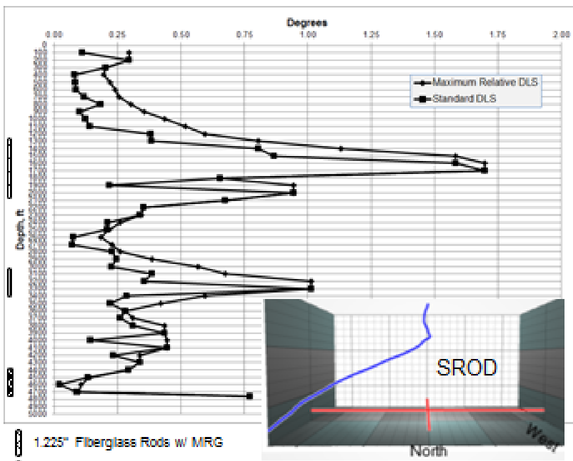


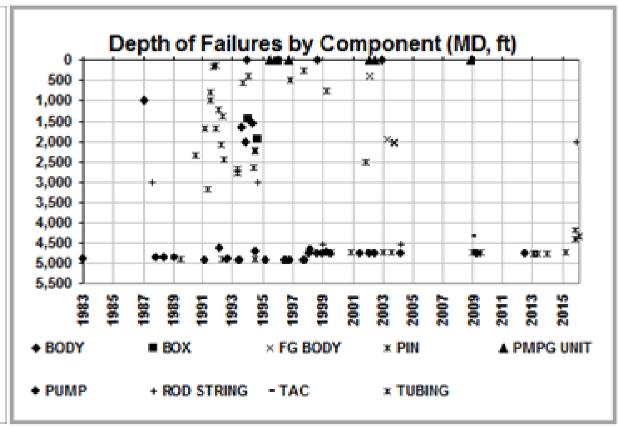


7/8" Steel Rods w/ MRG

3/4" Steel Rods w/ MRG

9335



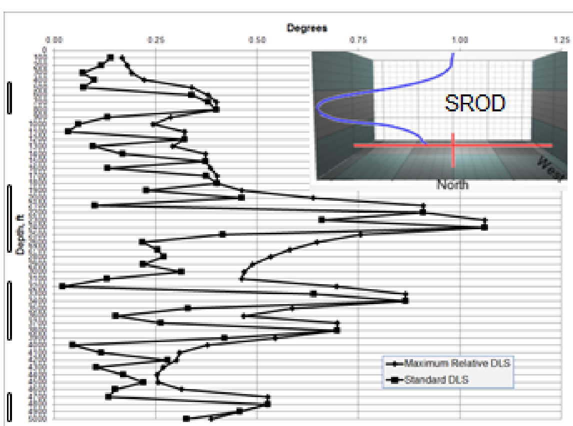


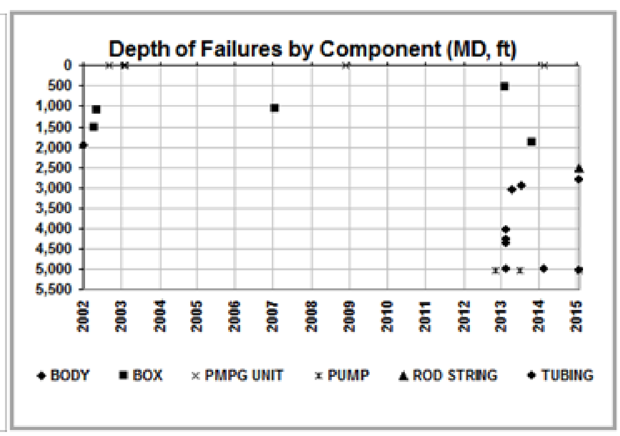
1.225" Fiberglass Rods w/ MRG

7/8" Steel Rods w/ MRG

3-1/2" Poly-lined tubing

9354

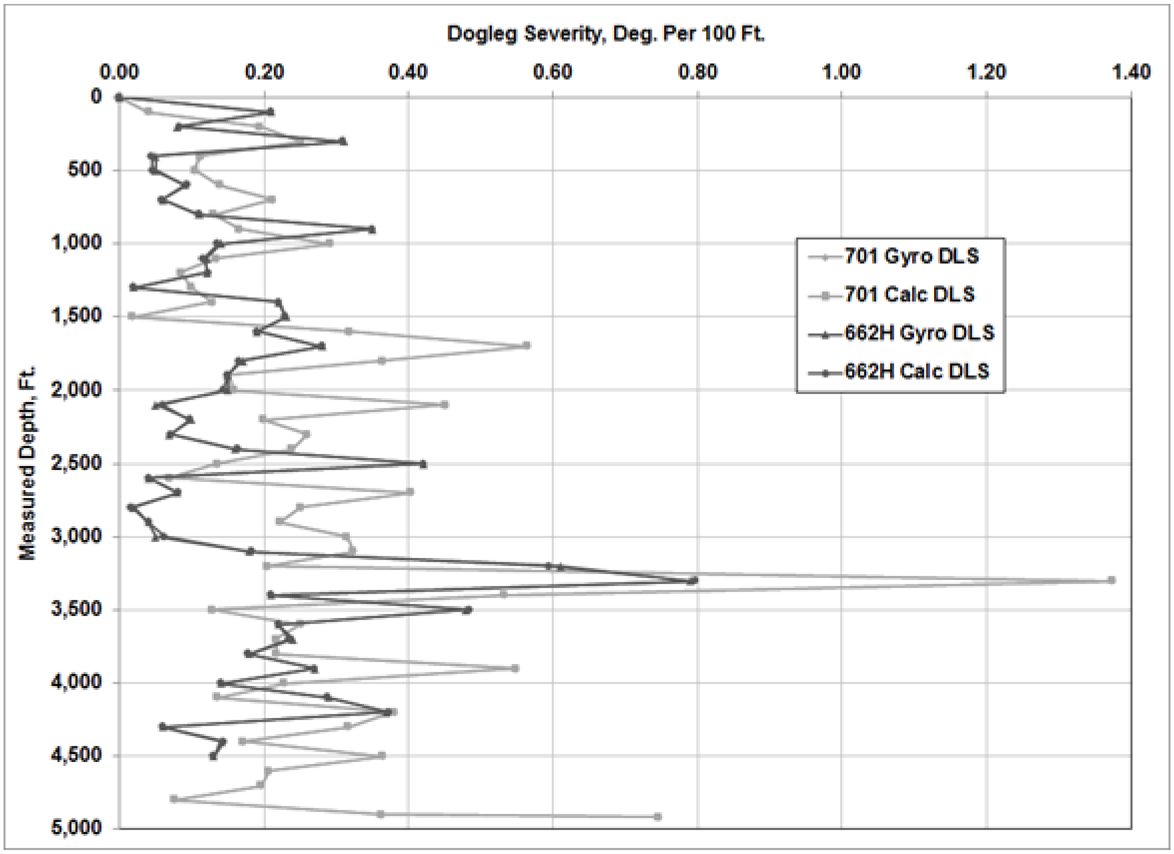




7/8" Steel Rods w/ MRG

3/4" Steel Rods w/ MRG

Figure 12



Survey Method:
701 – Minimum Curvature
662H - Unknown

Calculation Method	TVD Error, Ft.	Displacement Error, Ft.
Tangential	-4.76	+14.99
Balanced Tangential	-0.11	-0.03
Average Angle	0.00	-0.25
Curvature Radius	-0.04	-0.31
Minimum Curvature	-----	-----

Source: Sperry-Sun test hole

Figure 13